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GOVERNMENT OF PUERTO RICO
PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: IMPLEMENTATION OF THE PUERTO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN AND MODIFIED ACTION PLAN

CASE NO.: NEPR-MI-2020-0012

SUBJECT: Motion in Compliance with February 3, 2021 Order, and Request for Confidential Treatment

MOTION IN COMPLIANCE WITH ORDER SUBMITTING INFORMATION ON WEIGHTED CRITERIA USED TO EVALUATE AND CHOOSE THE PROJECTS TO ACQUIRE 150 MW OF RENEWABLE ENERGY

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

COMES NOW the Puerto Rico Electric Power Authority ("PREPA") through the undersigned legal representation and respectfully submits and requests as follows:

1. On March 3, 2021 the Puerto Rico Energy Bureau for the Public Service Regulatory Board ("Energy Bureau") entered Resolution and Order requiring PREPA to submit unredacted versions of Exhibit A that had been attached to *"Motion in Compliance with Order Submitting list of Projects PREPA will Potentially Choose to Acquire 150 MW of Renewable Energy"* ("Motion Submitting") filed with the Energy Bureau on February 9, 2021.
2. The Motion Submitting was filed by PREPA in response to Order entered by the Energy Bureau on February 3, 2021, requiring PREPA to submit by February 9, 2021 "[a] list of the renewable energy projects PREPA will choose to acquire 150 MW from amongst the 16 proposed projects for which PREPA had requested and later withdrew petitions for the Energy Bureau's approval to execute the corresponding Power Purchase and Operation Agreements ("PPOAs")."

3. On March 8, 2021 PREPA submitted the unredacted portions of Exhibit A which had become public information.

4. The March 3, 2021 Resolution and Order also required PREPA to file, with the Energy Bureau by March 15, 2021, information regarding "the weighted criteria used [by PREPA] to evaluate the 16 proposed projects and ultimately identify the projects listed in the Exhibit A."

5. To evaluate the 16 remaining legacy solar power purchase and operating agreements ("PPOAs") for the acquisition of 150MW of renewable energy as requested by the Financial, Oversight and Management Board for Puerto Rico ("Oversight Board") PREPA commissioned New Energy Partners ("NEP"), a PREPA consultant, to evaluate the projects. On December 30, 2020, NEP submitted an objective and independent analysis report which included recommendations for which solar PPOAs to advance for negotiation and the rank order of the projects.

6. In compliance with Order, PREPA hereby submits, as Exhibit A, New Energy Partners Inc. "Review of Legacy Solar PV PPOA's and Recommendations for Ranking and Negotiations Final Report" dated December 30, 2020 ("NEP Report") which details the weighted criteria used by PREPA to choose from among the 16 proposed PPOA projects.

WHEREFORE, in compliance with order, PREPA SUBMITS the NEP Report, as Exhibit A, which details the weighted criteria used by PREPA to choose from among the 16 proposed PPOA projects.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 15th day of March 2021.

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Exhibit A to the Motion

New Energy Partners Inc. “Review of Legacy Solar PV PPOA’s and Recommendations for Ranking and Negotiation Final Report” December 30, 2020

REVIEW OF LEGACY SOLAR PV PPOAS AND RECOMMENDATIONS FOR RANKING AND NEGOTIATIONS

FINAL REPORT

DECEMBER 30, 2020

FOR PUERTO RICO ELECTRIC POWER AUTHORITY
WORKED PERFORMED UNDER CONTRACT 2021-P0060

SUBMITTED BY:
NEW ENERGY PARTNERS, INC.

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PREPA SOLAR PPOA RANKING:

Executive Summary

The PREPA Board must make a decision as to which of the 16 remaining legacy solar power purchase and operating agreements ("PPOAs") that agreed to the conditions of the PREB and FOMB[1] should be approved for negotiation. The FOMB limited PREPA to 150 MW of solar PPOAs that can be approved and FOMB along with PREB provided certain contractual conditions that the solar proponents must accept. The FOMB provided conceptual criteria for ranking, which formed the basis of this analysis.

Our recommendations of which solar PPOAs to advance for negotiation now and the rank order in which to negotiate are based on objective and independent analysis using a series of tests and criteria discussed in this report. We caveat that we relied on existing PREPA reports, Sargent &Lundy ("S&L") interconnection and development assessment, King and Spalding ("K&S") legal compliance, One Conexus ("Conexus") for assurance of financial strength and developer submitted data in performing these analyses.

We applied a two-stage evaluation process to all of the projects. In Stage One, we applied a series of pass/fail tests to determine each project's eligibility to move to stage two. To be considered in Stage Two, projects had to pass all six pass/fail tests. In Stage Two, we performed an analysis of the net financial benefit to PREPA ratepayers to rank order the projects, with secondary criteria in the event of a tie.

In Stage One, six pass/fail "gates" were used to determine which Solar PPOAs should be candidates to be approved for negotiation ranking order. These gates included: 1) Is the project in legal compliance with FOMB, PREB, and PREPA requirements? 2) Does the project have adequate financial strength, 3) Does the project fail PREPA's interconnection criteria on its own, based on the S&L report, 4) Does the project provide net financial benefits of greater than zero to ratepayers, 5) Is the project is late or mid stage development, and 6) Does the developer or developer group have experience equal to 10x the project scale?

Findings

Stage One: Six Projects Eliminated from contention due to stage one pass/fail criteria

Gate 1: King and Spalding has certified that all projects will be willing to proceed with negotiation of an updated PPOA that is compliant with the FOMB and PREB conditions and that K&S has a new master PPOA that can be used to update the preferred developer PPOAs immediately after the Board decision. No projects were eliminated by this gate.

[1] These conditions and the original FOMB letter of 8/17/20 were sent to solar developers by PREPA on 9/2/20

Gate 2: NEP makes no representation about the adequacy of financial strength of any of the developers, but instead relied on the analysis PREPA commissioned with Conexus. An initial review of financial strength for the top five projects was performed at PREPA's direction by the consulting firm Conexus based on the FOMB criteria. While Conexus found that some information necessary to complete the analysis was missing, the report indicates that they did find information substantiating that all of the top five developers had adequate financial backing and access to financing to proceed to the negotiations stage. Since Conexus did not find sufficient information to conclude that any of the developers met *all* of the FOMB tests, PREPA will need to obtain the missing information during the negotiation phase of the process, and make their own conclusions regarding financial strength, as discussed in the "Negotiation Approach" section.

Gate 3: Two projects failed the interconnection criteria. Montalva and Fonroche San Juan. These were removed from consideration in this round after confirmation of concerns from PREPA operations, as discussed in Section III.

Gate 4: All projects passed the public benefit test. The amount of public benefit per MW, which is ranked in stage two of the process, varied by an order of magnitude. Therefore, no projects were eliminated by this gate.

Gate 5: S&L evaluated all the projects that submitted the actual documentation in determining project stage. In addition, S&L evaluated those that submitted letters representing they had the relevant permits, site control, etc. One project, Atenas, submitted no documentation or reference table and was eliminated for contention. Another project, Morovis, submitted their interest in participating too late to be accepted, and never submitted the required documentation to show the current status of their project. Therefore, Morovis was eliminated.

Gate 6: Two projects from the same developer, Sierra and Caracol, failed the developer experience test, as the developer group did not have sufficient solar development experience at utility scale equal 10x the size of either project.

Stage 2: Rank Order remaining projects based on Public Benefits and secondary criteria

Ten projects remained after applying the criteria in stage one. For those nine, we analyzed and ranked the present value energy cost savings net of interconnection costs. The results of this analysis are shown in Exhibit 1. Since FOMB constrained the amount of MW PREPA can contract for, the maximum public ratepayer benefit will be allocated for the most beneficial projects that successfully are in contention (pass all the project gates). In the event that the top projects are within 5% of each other, there are other criteria explained in Section I Methodology that would be used to rank between close projects. Given the wide differences in ratepayer value per MW, it was not necessary to address the secondary criteria.

Recommendations on Ranking Negotiation Order of PPOAs:

Understanding Ratepayer Value Ranking

NEP's November 2019 report assessed the lifetime benefit of the PPOA cost vs. the avoided energy cost in PREPA's base case IRP submission, netted against the cost of the interconnection that PREPA must pay for, to determine whether ratepayers would be better off. NEP used a blended discount rate to reflect PREPA current situation and the expectation of future credit improvement, consistent with the first analysis. In November 2019, several projects failed the public benefit test because the rate of 10.5¢/kwh was too high to generate any benefits to ratepayers, and the interconnection costs were often quite high. NEP recommended that any PPA rate be at or below 10¢/kwh *as a ceiling*, *not a target*, since this PPOA rate *just barely provides enough benefits to pay for interconnection.*

Unfortunately, most of the projects proposed this exact rate, given the Minimum Technical Requirement condition, and therefore have nearly identical net benefits to ratepayers. Only a few projects bid lower, which immediately provide significantly more ratepayer benefits, which lead to their higher ranking.

We recommend two projects be negotiated now: (1) Xzerta-Tec: 60 MW and (2) Ciro One: 90 MW. Since these total 150 MW, we discuss the nuances of negotiation given the responses in the next section.

If either of these fail upon finalization of diligence or refusal to honor the representations in their September 2nd final proposal letter, then the negotiations should proceed in the following contingent order: (3) REA Hatillo, (4) If Hatillo fails, then ReSun and Blue Beetle should be negotiated together since the synergies in sharing the interconnection line provide benefits to ratepayers. The remaining contingent order is shown below and described in greater detail in the section entitled " Negotiation Approach".

Exhibit 1
Recommendations on PPOA Ranking

Recommended Negotiation Ranking	PPOA NPV Value to Ratepayers ($/MW) (000s)	Adequate Financial Strength 3	Significant Development Experience?	Development Stage: could achieve construction in 8 months?
1. Xzerta Tec 60 MW	$3,645	Backing/ Access	Yes	Late
2. Ciro One 90MW	$961	Backing/ Access/	Yes	Late
3. REA Hatillo 25MW	$719	Backing/ Access/ Solvency	Yes	Mid(2)
(4) ReSun 35 MW	$914 1/$429	Backing/ Access	Yes	Late
(4) Blue Beetle 30 MW	$491 1/$431	Backing/ Access Solvency	Yes	Late
(5) Solaner 35 MW	$381	N/R	Yes	Late
(5) Guayama 25 MW	$363	N/R	Yes	Late
6. Solar Blue 25 MW	$326	N/R	Yes	Late
7. REA Vega Baja 25 MW	$281	N/R	Yes	Late
8. Fonroche Vega Baja 15 MW	$260	N/R	Yes	Mid

Green indicates top proponent, **Yellow** indicates similar value band.
1. Resun and Blue Beetle can share interconnection costs when selected together. Therefore, the first stated value is contingent on both projects being accepted. The second value is the stand alone.
2. Documentation not provided. S&L assessment is mid stage at best.
3. FOMB criteria meet by the developers listed below. N/R means not rated.

The Conexus review of the top projects makes it clear each of them has reputable financial backers and access to financing: Xzerta-Tec (joint venture with Orgis Energy) and CIRO One (GCL/Putnam Bridge), REA (MasTec), ReSun (Orgis Energy), and Blue Beetle (OPD Energy).

Negotiation Approach

Xzerta-Tec's letter submission on 9/2/20 offered a lower rate of $99/Mwh escalated at 1% with cap at 12.6¢/Mwh. Xzerta-Tec, along with 6 other companies, submitted a list of its development accomplishments, instead of submitting all the actual documents. In initial negotiations, we recommend that PREPA request and review all documentation as well as present the updated PPOA with the new pricing.

To complete the financial review, the following information should be validated. For all of the top 5, PREPA should request a commercial credit worthiness report to ensure the financial backers are investment grade (e.g. , S&P BBB or better, or D&B composite credit appraisal rating of 2 or better).

For Xzerta-Tec, PREPA should obtain and review the joint venture agreement with Orgis, as well as a financial statement from Orgis (which is also the backer of ReSun). The Orgis financial statements can then be used to confirm financial solvency.

If upon review, it is revealed that the developer made a misrepresentation on some other material fact, then the ranking should be executed to negotiate with the next project. This approach will be valid for all developers that submitted letters as opposed to the actual documents.

Many, if not all proponents, have a legitimate technical issue with the PREB order of 8 months after the PPOA signing vs. 8 months after "Assumption Order" of "Effective date", as defined in the PPOA itself. The developers have a valid concern about their ability to lock in financing or give a true full notice to proceed before their PPOA gets assumed. This is due to the risk that until the court issues the Assumption Order the PPOA itself could be rejected. Neither Ciro One nor Xzerta raised an objection to this. The K&S letter describing the issue suggests that this may need to be a point requiring clarification with the PREB. If PREB doesn’t agree with the clarification, and PREPA can’t reach final agreement with a preferred developer on the required term, then PREPA can move down the list to the next most attractive developer. For more detail, please see the letter from King and Spalding regarding this issue and how to resolve it.

I. Methodology

NEP used a transparent and fact-based approach to ranking these projects that is compliant with the FOMB criteria in its August 17, 2020 letter and PREB Order. NEP worked in partnership with PREPA (financial strength) and its advisors, Sargent and Lundy (interconnection and readiness) and King & Spaulding (PPOA Compliance).

We then applied a two-stage evaluation process to all of the projects. First, we applied a series of pass/fail tests to determine each project's eligibility to move to stage two. Each step is a "gate". The gates are not sequential. We conducted parallel analysis on responsive developers across all gates. Projects that fail any gate are removed from consideration for this negotiation and may apply for the upcoming RFP. Next, we performed an analysis of the net financial benefit to PREPA ratepayers to rank order the projects.

Stage 1 Pass/Fail Gates

Gate 1: Legal Contractual Compliance: All projects must be willing to sign the updated PPOA that is entirely consistent with the FOMB criteria listed on page 4 of the August 17 2020 letter related to transferability, and changes to Section 6.5(c), Section 20.3 and Section 20.4., as well as the PREB additional conditions. All projects must meet PREPAs MTRs. It should be noted that multiple projects used batteries to meet the MTRs. All of these conditions were explained in the letter from PREPA to the project proponents on September 2, 2020. NEP is relying on the written statement from King and Spalding that the updated master PPOA is compliant with all the FOMB mandated changes and they have written acceptance of these changes from the developers (see attached letter). Any project not certified by K&S will be removed from consideration for 2020.

Gate 2: Financial Compliance and Due Diligence on Financial Strength: The FOMB has set the net worth requirements at $25 MM for any new owners and $75 MM for any new parent entity. In addition to these requirements, the standard financial due diligence to ensure the developer has adequate equity secured to fund its share of the proposed project, has secured financing, has robust financial statements or financial backing from reputable investors and that there are no financial red flags in solvency and proof of credit worthiness. PREPA has specific objective tests to be compliant with the FOMB letter directive which the PREPA financial analyst team and its consultant is evaluating based on the documentation provided by the developers. Project that fail these objective tests will be removed from consideration. As stated above, we recommend that PREPA require developers to submit additional documentation during the negotiation stage to permit it to complete the financial analysis required by FOMB.

Gate 3: Interconnection Concerns: Sargent and Lundy reevaluated and redesigned the interconnection for these projects (Report CS-0034). If a project, operating on its own, would be curtailed based on violations of the PREPA N-1, N-2 or N-1-1 contingency test, then it will be placed in the provisional category unless S&L can provide a number of expect hours per year of curtailment for the projects, which will then be added to the costs in Gate 4. S&L has informed NEP that it did not do a system evaluation, only an interconnection evaluation, so it can not determine the frequency of curtailment. Since upgrades to the PREPA system will now be governed by Luma's System Remediation Plan, which is still in development, PREPA must prudently determine that the selected projects in 2020 will indeed operate and contribute to the PREB Order RPS requirements in 2021. Given these circumstances, it is prudent for PREPA to remove these projects from consideration, though they can apply for the RFPs that Luma will be overseeing. NEP has completed work with S&L to confirm the reports findings.

Gate 4 Public Benefits Test: NEP will financially re-evaluate whether the projects with the new PPOA prices and updated interconnection costs in S&L Report CS-0034 would provide benefits to ratepayers based on the average base case IRP avoided costs submitted and implicitly approved by the PREB IRP order, REC Price and blended discount rate used in the NEP December 2019 evaluation of the PPOAs. Any projects that fail the NPV test will not be considered for 2020 negotiations.

Gate 5 Development Stage: Ability to Start Construction in 8 months: Any project that is early stage development or where remaining development items could not be addressed by September 2021 (9 months), will be excluded from this evaluation. NEP will rely on the S&L evaluation currently underway.

Gate 6 Solar Development Experience: All developers must show that they have experience in developing solar projects that are cumulative 10x the scale of their proposed project and have developed at least one project of the same scale, whether in Puerto Rico or elsewhere.

Stage 2: Ranking of Remaining Projects

The remaining projects are rank ordered based on the following hierarchy of criteria. Since the scarce resource on the system is 150 MW of capacity, which was limited by FOMB, and the PREB is clearly interested in ensuring projects are built in 2021, NEP applied the criteria and data from Stage 1 in the following way.

The projects are first ranked by their value to PREPA ratepayers on an NPV $/MW basis. This ensures a "pareto" optimization of ratepayer value, in essence maximizing the ratepayer value of the 150 MW of allowable contracts.

If any two projects have a ratepayer value within 5% of each other, then secondary criteria are applied. The next most important subsequent criteria is time: if a project is in a later stage of development, then it is given negotiation order preference.

If both projects have are in the same stage of development, then then if one project has Puerto Rican development experience, it is given negotiation order preference. The logic is that companies with prior experience would have a time advantage over those that do not.

II. Ranking of Potential Projects

The ranking of potential projects is provided in the executive summary. In the final report, when all the data has been provided by PREPA, we will update the ranking table if needed.

As noted above, projects that were eliminated were not forced ranked. However, to be complete, NEP did perform the same analysis on all projects, whether they were eliminated or not.

For the remaining projects, the primary criteria is the value to ratepayers per MW. As a reminder, this is due to FOMB limiting the number of MW that can be procured, and therefore, PREPA's desire to ensure that the maximum benefit is provided to ratepayers. This calculation is based on the net present value of lifetime energy savings compared with avoided cost, at the blended discount rate used in the NEP 2019 study, since PREPA has still not yet emerged from bankruptcy. We then subtract the interconnection costs from this value to arrive at "Net benefit to ratepayers". We divide the "Net benefit to ratepayers" by the project output capacity in MW to arrive at a net benefit to ratepayers per MW. The projects are then forced ranked by this criteria.

While the top projects clearly were significantly more valuable to ratepayers, there were two cases where projects were essentially "tied": Case 1: Blue Beetle and Resun, and Case 2: Solaner and Guayama. All of these projects are considered late stage by S&L. Whether any project, irrespective of stage could credibly meet the PREB condition of construction within 8 months of signing a PPOA, without the contract assumption is unknown given the financing contingency. None of these proponents are particularly distinguished by Puerto Rican development experience.

Since the top two projects represent 150 MW, the issue of further ranking may be moot. However, for the avoidance of doubt, we recommend the following algorithm in the event that negotiations with either of the top two fail:

1) The next project to be considered is REA Hatillo. If the claims of ability to obtain permits and/or pricing proves to be misrepresentations upon final diligence, then this project would be eliminated.

2). If CIRO One negotiations fail, and REA Hatillo negotiations are successful, then Blue Beetle and ReSun should be negotiated together to obtain the savings to ratepayers of the shared interconnection line.

3). If Xzerta Tec and REA Hatillo negotiations fail, then Blue Beetle and ReSun should be negotiated together to obtain the savings to ratepayers of the shared interconnection line. PREPA should petition FOMB to allow it to go over the cap of 150 MW by 5 MW based on the "common sense" test that all regulators should support the goals of increasing renewable energy with clear benefits to ratepayers. As independent projects these are both still viable, so if only one goes forward, then PREPA would have to go the next project band for the remaining capacity.

4) If Xzerta Tec negotiations failed and REA Hatillo negotiations are successful, then PREPA has a conundrum since both Blue Beetle and ReSun are tied based on legitimate criteria. In this contingency, we recommend one of two approaches. PREPA should petition FOMB to allow it to go over the 150 MW cap by 25 MW based on the "common sense" test that all regulators should support the goals of increasing renewable energy with clear benefits to ratepayers. If successful, PREPA can secure both contracts, and ratepayers will be better off. Should FOMB be inflexible, PREPA can request each proponent give a best and final offer and take the lowest one, even if the differences are slight.

We do not expect that the negotiations would reach into the next group of projects, but if they did, the same logic would apply.

III. Basis for Elimination of Projects that Failed Tests

Six projects were eliminated in Stage 1. This section provides a brief discussion of them.

Inadequate Solar Development Experience

Two projects, Sierra (25MW) and Caracol (30MW), has the same parent company and development team from Aleron RE, a subsidiary of the Hartz Group (THGI). THGI is a real estate developer that has cumulatively developed 50MW. Of this, one was utility scale wind project (34 MW), the other a small community wind/solar project. THGI has no experience developing even a 20 MW utility scale PV project. This is not even a 1:1 cumulative experience level at utility scale. While the Hartz Group's EPC contractor (DEPCOM) has significant experience in building and construction solar projects, the intention of the criteria was the experience of the development team (inclusive of its financial consortium). This lack of experience is the basis for elimination of what otherwise would have been a low cost, later stage pair of projects.

Inadequate Documentation of Financial Strength, Project Stage, and Utility Scale Experience

One developer, National Energy Partners, Atenas, provided no documentation of financial strength. Further, this company reduced its scale from 40 to 20 MW in its response letter to PREPA, despite the efforts by S&L to negotiate with them on the interconnection of 40 MW. This considerably reduces their ratepayer value ranking. The company provided no evidence of utility scale solar experience, and their web sites provides only residential and commercial projects. The company did list four approvals (Department of Agriculture, Environmental Quality Board, Planning Authority and Solid Waste Authority) but offered no evidence that it had maintained site control. For these reasons, this project was eliminated from contention.

Another developer, X-Elio for the Morovis project, submitted too late after the deadline to be fairly considered. Its response indicated it would be submitting further documentation which it did not provide. For these reasons, it was eliminated from contention.

Interconnection Test Contingency Violations

The interconnection test criteria applied is that if a project, solely on its own, violates PREPA interconnection criteria, such that if such a contingent event occurred (e.g., N-1 or N-1-1), then the project would be curtailed. The interconnection assessment was performed by S&L in report CS-0034, Final Rev 1 June 19, 2020 Project 13741.017. Even though two projects failed the interconnection tests, these projects were submitted as part of the May 2020 board approval package and subsequently approved. Therefore, the basis for NEP's recommendation of elimination based on these same criteria and evidence requires explanation.

At the time of the Board's approval, PREPA was still in charge of its grid and future upgrades. Therefore, PREPA could prioritize T&D line improvements that could address the N-1 or N-1-1 situation, which is typically caused by a weak transmission line as the initial contingency. Further, PREPA had at that time the ability to assess the likelihood of line failure and the additional costs in both expected curtailment payments and additional generation reserves necessary to accept the risk of these contracts. Given the new PPOAs have a low threshold for outages and are take or pay (e.g. PREPA must pay developer if curtailment exceeds the contractual minimum threshold), it is important to factor in these costs into the present value to ratepayers.

As of November 2020, PREPA no longer has control over future grid improvements, these are to be done by Luma in the System Remediation Plan. This in the case of Montalva, the initial contingency is Line 37100, which " is considered a weak line and frequently trips, particularly in the section between Acacias TC and San German". The reason given is that the "115/38kV step down transformer in the Guanica TC is currently not in service". Therefore, S&L modeled this weak line as an N-1-0 outage for the N-1-1, i.e., this expected outage is combined with other contingency cases. S&L stated in communication with NEP that the interconnection itself does not alleviate the situation. S&L notes that at 73 MW Montalva alone does not trigger any contingency. However, at 80 MW it does if the second contingency is the loss of the line east of the

Montalva sectionalizer. Under the Montalva PPOA Appendix B, Montalva is required to implement a protection scheme that will automatically curtail the total generation of the facility, if necessary, when an N-1-1 contingency in transmission line L-37100." While this approach will mitigate overloading of the San German TC and associated 38kV grid, these failures would be "grid events" within the PPOA.

There are two costs to PREPA ratepayers if such an event occurs. First, if the hours of curtailment are greater than the contract minimum, specified at 40 hours/year for grid events, then PREPA must pay the developer for the electricity it would otherwise have delivered. Second, generation in the form of spinning reserves must be available on the system to address such an outage to avoid load shedding. For a project of this scale, this second criteria can be problematic. Although PREPA keeps ~400-450 MW of spinning reserve available, when a generation outage, such as the recent event of Costa Sur outage due to earthquake occurs, or depending on the amount of planned generation maintenance, there would simply have been no reserves left on the system to cover a solar contingency of this magnitude.

For these reasons, NEP advises that projects that fail the PREPA contingencies be eliminated from the round, without prejudice for future RFPs unless PREPA receives direct confirmation from Luma that, in the case of Montalva, Line 37100 issues would be fixed in the SRP before Montalva comes on line. Similarly, in the case of Project San Juan, the issues are in Line 9300 and there is a particular segment which is out of services within the PSS/E model. We recognize that this a conservative position taken from an abundance of caution given the continued weakness of the PREPA T&D grid and generation situation.

IV. Recommendations

We recommend two projects be negotiated now: (1) Xzerta-Tec: 60 MW and (2) Ciro One: 90 MW.

If either of these fail upon finalization of diligence or refusal to honor the representations in their September 2nd final proposal letter, then the negotiations should proceed in the following contingent order: (3) REA Hatillo, (4) If Hatillo fails, then ReSun and Blue Beetle should be negotiated together since the synergies in sharing the interconnection line provide benefits to ratepayers.

We strongly urge PREPA to move forward expeditiously. We recommend informing the regulators, FOMB and the PREB of PREPA's decision and the underlying rationale. We would recommend requesting PREB to clarify that the requirement related to commencement of construction is intended to be 8 months after “assumption” when PREPA refiles the two preferred agreements with them (see King and Spalding letter).

Similarly, it would be helpful to secure any pre-approvals from FOMB regarding possible contingent exceedance of the 150 MW cap in order to benefit ratepayers, should negotiation with the two recommended proponents fail.

Xzerta valuation COMPARISON ESM IRP AND CERTIFIED FISCAL PLAN

PPOA Start Date Per FOMB		**2020**
PPOA Price $Mwh		**99**
PPOA Escalator		**1%**
PPOA Cap $/Mwh	**$**	**126**
Inflation		2%
Discount rate 2023-2045		8.5%
Discount Rate 2019-2022		13.5%
Hedge Premium 2025-2045		8%

	2020	2021	2022	2023	2024
CME Forward Hedge Premium v 2019 Forecast 10/14/19	6%	8%	10%	11%	12%

1 2 3 4

MARGINAL UNIT		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ESM IRP BASE CASE		ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC
CFP 2020 SUBMITTED					ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-GAS	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC
MARGINAL FUEL AND VARIABLE O&M ($/Mwh)																												
MARGINAL GEN COST ESM IRP		118	124	121	122	124	125	67	69	70	72	71	72	73	75	76	78	80	81	82	83	84	85	86	86	87	88	89
MARGINAL GEN COST CFP					70	93	108	118	124	95	75	76	77	79	80	82	83	84	85	84.0	85.0	86.1	88	90	91	93	95	97
DIFFERENTIAL					-53	-32	-17	50	55	25	3	4	5	6	5	6	5	4	4	2	2	2	3	4	5	6	7	8
MARGIN GEN COST CFP + NEAR TERM		118	124	121	70	93	108	118	124	95	75	76	77	79	80	82	83	84	85	84	85	86	88	90	91	93	95	97
Certfied Fiscal plan is unhedged variable costs are slight more expensive than ESM IRP.																												
NPV UNHEDGED VARIABLE COST ONLY																												
NPV ESM IRP UNHEDGED VARIABLE COST ONLY	$794		124	121	122	$840.0																						
NPV CFP UNHEDGED VARIABLE COST ONLY	$805		124	121	70	$919.5																						
FULL AVOIDED COSTS																												
Add Environmental REC Credit		15.0	15.3	15.6	15.9	16.2	16.6	16.9	17.2	17.6	17.9	18.3	18.7	19.0	19.4	19.8	20.2	20.6	21.0	21.4	21.9	22.3	22.7	23.2	23.7	24.1	24.6	25.1
ADD: HEDGE VALUE FOR ESM IRP		0.0	8.0	9.7	12.0	13.3	15.5	5.4	5.6	5.6	5.7	5.7	5.8	5.8	6.0	6.1	6.2	6.4	6.5	6.6	6.6	6.7	6.8	6.8	6.9	7.0	7.1	7.1
AVOIDED COST ESM IRP		**133.0**	**147.4**	**146.7**	**150.4**	**153.9**	**157.2**	**89.6**	**92.2**	**93.4**	**95.2**	**95.4**	**96.8**	**97.6**	**100.1**	**101.7**	**104.1**	**106.5**	**108.2**	**110.3**	**111.6**	**112.9**	**114.3**	**115.7**	**117.0**	**118.5**	**119.9**	**121.3**
Combined Avoided Cost $/Mwh		133.0	147.4	146.7	150.4	153.9	157.2	89.6	92.2	93.4	95.2	95.4	96.8	97.6	100.1	101.7	104.1	106.5	108.2	110.3	111.6	112.9	114.3	115.7	117.0	118.5	119.9	121.3
Xzerta PPOA $/Mwh			99	100.0	101.0	102.0	103.0	104.0	105.1	106.1	107.2	108.3	109.4	110.5	111.6	112.7	113.8	114.9	116.1	117.2	118.4	119.6	120.8	121.6	121.6	121.6	121.6	121.6
Net Savings/Cost v Avoid Cost $/Mwh			$48.4	$46.7	$49.4	$51.9	$54.2	($14.5)	($12.9)	($12.7)	($12.0)	($12.9)	($12.5)	($12.8)	($11.4)	($11.0)	($9.7)	($8.5)	($7.8)	($7.0)	($6.8)	($6.7)	($6.5)	($5.9)	($4.6)	($3.1)	($1.7)	($0.3)
2023-2045 NPV @ 8.5%						$8.76																						
NPV 13.5% of 2020-2022+ NPV 13.5%of NPV2023-2045	$118.70		$48.4	$46.7	$58.13																							
Add Environmental REC Credit		15.0	15.3	15.6	15.9	16.2	16.6	16.9	17.2	17.6	17.9	18.3	18.7	19.0	19.4	19.8	20.2	20.6	21.0	21.4	21.9	22.3	22.7	23.2	23.7	24.1	24.6	25.1
ADD: HEDGE VALUE FOR CFP IRP			8.0	9.7	6.8	9.9	13.4	9.4	10.0	7.6	6.0	6.1	6.2	6.3	6.4	6.5	6.6	6.7	6.8	6.7	6.8	6.9	7.0	7.2	7.3	7.5	7.6	7.8
AVOIDED COST CFP		**133.0**	**147.4**	**146.7**	**92.4**	**118.8**	**138.2**	**144.1**	**151.7**	**120.6**	**98.9**	**100.2**	**102.2**	**104.1**	**106.0**	**107.9**	**109.6**	**111.0**	**113.0**	**112.1**	**113.7**	**115.3**	**117.6**	**119.9**	**122.3**	**124.8**	**127.3**	**129.8**
Xzerta PPOA $/Mwh			99	100.0	101.0	102.0	103.0	104.0	105.1	106.1	107.2	108.3	109.4	110.5	111.6	112.7	113.8	114.9	116.1	117.2	118.4	119.6	120.8	121.6	121.6	121.6	121.6	121.6
Net Savings/Cost v Avoid Cost $/Mwh			$48.4	$46.7	($8.6)	$16.8	$35.2	$40.0	$46.6	$14.4	($8.3)	($8.0)	($7.2)	($6.3)	($5.6)	($4.8)	($4.2)	($4.0)	($3.1)	($5.1)	($4.8)	($4.3)	($3.2)	($1.7)	$0.7	$3.2	$5.7	$8.2
2023-2045 NPV @ 8.5%						$93.19																						
NPV 13.5% of 2020-2022+ NPV 13.5%of NPV2023-2045	$136.80		$48.4	$46.7	$84.60																							
CFP shows more value under same methodology																												
CFP starts in 2022 so 2020,2021 ESM data used to allow same discount comparison																												
In General, CFP hedge costs are more expensive NPV than ESM IRP																												
NPV AVOIDED COST ESM IRP	$1,012		147.4	146.7	150.4	$1,104.48																						
NPV AVOIDED COST CFP	$1,023		147.4	146.7	92.4	$1,188.92																						
DIFFERENCE IN NPV $/MWH	$11																											
DIFFERENCE IN NPV $/MWH					$26.47																							

CALCULATION OF MARGIN GEN COST IN CERTIFIED FISCAL PLAN

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
ST SFO TOTAL COST	260,933	282,550	237,284	172,938	89,960													
ST SFO FIXED COST	30,278	30,811	26,317	21,553	10,966													
NET ST SFO COST	230,656	251,739	210,967	151,385	78,994													
ST SFO GENERATION MWH	3,311,734	2,717,107	1,949,662	1,285,433	634,566													
NET ST SFO COST/MWH	69.6	92.6	108.2	117.8	124.5													
ST GASTOTAL COST						78,877												
ST GAS FIXED COST						10,966												
NET ST GAS COST						67,911												
ST GAS GENERATION MWH						712,003												
NET ST GAS COST/MWH						95.4												
NG CC TOTAL COST							71,923	93,073	89,907	85,595	80,914	109,240	112,556	111,451	57,269			
NG CC FIXED COST							31,081	31,573	32,171	32,780	33,486	34,031	34,680	35,333	17,979			
NET NG CC COST							40,841	61,500	57,737	52,815	47,427	75,208	77,876	76,117	39,290			
NG CC GENERATION MWH							544,408	810,413	746,313	670,327	591,539	921,825	940,981	909,681	461,293			
NET NG CC COST/MWH							75	76	77	79	80	82	83	84	85			
LARGE NG CC TOTAL COST																438,592	434,773	430,250
LARGE NG CC FIXED COST																148,698	149,053	149,418
NET LARGE NG CC COST																289,895	285,720	280,833
LARGE NG CC GENERATION MWH																3,452,707	3,360,965	3,261,489
NET LARGE NG CC COST/MWH																84.0	85.0	86.1

CIRO valuation COMPARISON ESM IRP AND CERTIFIED FISCAL PLAN

PPOA Start Date Per FOMB	**2020**					
PPOA Price $Mwh	**98.9**					
PPOA Escalator	**2%**					
PPOA Cap $/Mwh	**$ 141**					
Inflation	2%					
Discount rate 2023-2045	8.5%					
Discount Rate 2019-2022	13.5%					
Hedge Premium 2025-2045	8%					
		2020	2021	2022	2023	2024
CME Forward Hedge Premium v 2019 Forecast 10/14/19		6%	8%	10%	11%	12%

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MARGINAL UNIT		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ESM IRP BASE CASE		ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC
CFP 2020 SUBMITTED					ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-GAS	GAS CC	GAS CC	GAS CC	GAS CC
MARGINAL FUEL AND VARIABLE O&M ($/Mwh)														
MARGINAL GEN COST ESM IRP		118	124	121	122	124	125	67	69	70	72	71	72	73
MARGINAL GEN COST CFP					70	93	108	118	124	95	75	76	77	79
DIFFERENTIAL					-53	-32	-17	50	55	25	3	4	5	6
MARGIN GEN COST CFP + NEAR TERM		118	124	121	70	93	108	118	124	95	75	76	77	79
Certfied Fiscal plan is unhedged variable costs are slight more expensive than ESM IRP.														
NPV UNHEDGED VARIABLE COST ONLY														
NPV ESM IRP UNHEDGED VARIABLE COST ONLY	$794		124	121	122	$840.0								
NPV CFP UNHEDGED VARIABLE COST ONLY	$805		124	121	70	$919.5								
FULL AVOIDED COSTS														
Add Environmental REC Credit		15.0	15.3	15.6	15.9	16.2	16.6	16.9	17.2	17.6	17.9	18.3	18.7	19.0
ADD: HEDGE VALUE FOR ESM IRP		0.0	8.0	9.7	12.0	13.3	15.5	5.4	5.6	5.6	5.7	5.7	5.8	5.8
AVOIDED COST ESM IRP		**133.0**	**147.4**	**146.7**	**150.4**	**153.9**	**157.2**	**89.6**	**92.2**	**93.4**	**95.2**	**95.4**	**96.8**	**97.6**
Combined Avoided Cost $/Mwh		133.0	147.4	146.7	150.4	153.9	157.2	89.6	92.2	93.4	95.2	95.4	96.8	97.6
Ciro PPOA $/Mwh			98.9	100.9	102.9	105.0	107.1	109.2	111.4	113.6	115.9	118.2	120.6	123.0
Net Savings/Cost v Avoid Cost $/Mwh			$48.5	$45.8	$47.5	$49.0	$50.2	($19.6)	($19.2)	($20.2)	($20.7)	($22.8)	($23.7)	($25.3)
2023-2045 NPV @ 8.5%						($104.86)								
NPV 13.5% of 2020-2022+ NPV 13.5%of NPV2023-2045	$39.09		$48.5	$45.8	($57.39)									
Add Environmental REC Credit		15.0	15.3	15.6	15.9	16.2	16.6	16.9	17.2	17.6	17.9	18.3	18.7	19.0
ADD: HEDGE VALUE FOR CFP IRP			8.0	9.7	6.8	9.9	13.4	9.4	10.0	7.6	6.0	6.1	6.2	6.3
AVOIDED COST CFP		**133.0**	**147.4**	**146.7**	**92.4**	**118.8**	**138.2**	**144.1**	**151.7**	**120.6**	**98.9**	**100.2**	**102.2**	**104.1**
CIRO PPOA $/Mwh			98.9	100.9	102.9	105.0	107.1	109.2	111.4	113.6	115.9	118.2	120.6	123.0
Net Savings/Cost v Avoid Cost $/Mwh			$48.5	$45.8	($10.5)	$13.9	$31.1	$34.9	$40.3	$7.0	($16.9)	($18.0)	($18.4)	($18.9)
2023-2045 NPV @ 8.5%						($20.42)								
NPV 13.5% of 2020-2022+ NPV 13.5%of NPV2023-2045	$57.20		$48.5	$45.8	($30.91)									
CFP shows more value under same methodology														
CFP starts in 2022 so 2020,2021 ESM data used to allow same discount comparison														
In General, CFP hedge costs are more expensive NPV than ESM IRP														
NPV AVOIDED COST ESM IRP	$1,012		147.4	146.7	150.4	$1,104.48								
NPV AVOIDED COST CFP	$1,023		147.4	146.7	92.4	$1,188.92								
DIFFERENCE IN NPV $/MWH	$11													
DIFFERENCE IN NPV $/MWH					$26.47									

MARGINAL UNIT	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ESM IRP BASE CASE	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC
CFP 2020 SUBMITTED	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC
MARGINAL GEN COST ESM IRP	75	76	78	80	81	82	83	84	85	86	86	87	88	89
MARGINAL GEN COST CFP	80	82	83	84	85	84.0	85.0	86.1	88	90	91	93	95	97
DIFFERENTIAL	5	6	5	4	4	2	2	2	3	4	5	6	7	8
MARGIN GEN COST CFP + NEAR TERM	80	82	83	84	85	84	85	86	88	90	91	93	95	97
Add Environmental REC Credit	19.4	19.8	20.2	20.6	21.0	21.4	21.9	22.3	22.7	23.2	23.7	24.1	24.6	25.1
ADD: HEDGE VALUE FOR ESM IRP	6.0	6.1	6.2	6.4	6.5	6.6	6.6	6.7	6.8	6.8	6.9	7.0	7.1	7.1
AVOIDED COST ESM IRP	**100.1**	**101.7**	**104.1**	**106.5**	**108.2**	**110.3**	**111.6**	**112.9**	**114.3**	**115.7**	**117.0**	**118.5**	**119.9**	**121.3**
Combined Avoided Cost $/Mwh	100.1	101.7	104.1	106.5	108.2	110.3	111.6	112.9	114.3	115.7	117.0	118.5	119.9	121.3
Ciro PPOA $/Mwh	125.4	127.9	130.5	133.1	135.8	138.5	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0
Net Savings/Cost v Avoid Cost $/Mwh	($25.3)	($26.3)	($26.4)	($26.6)	($27.5)	($28.2)	($29.4)	($28.1)	($26.7)	($25.3)	($24.0)	($22.5)	($21.1)	($19.7)
Add Environmental REC Credit	19.4	19.8	20.2	20.6	21.0	21.4	21.9	22.3	22.7	23.2	23.7	24.1	24.6	25.1
ADD: HEDGE VALUE FOR CFP IRP	6.4	6.5	6.6	6.7	6.8	6.7	6.8	6.9	7.0	7.2	7.3	7.5	7.6	7.8
AVOIDED COST CFP	**106.0**	**107.9**	**109.6**	**111.0**	**113.0**	**112.1**	**113.7**	**115.3**	**117.6**	**119.9**	**122.3**	**124.8**	**127.3**	**129.8**
CIRO PPOA $/Mwh	125.4	127.9	130.5	133.1	135.8	138.5	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0
Net Savings/Cost v Avoid Cost $/Mwh	($19.4)	($20.0)	($20.9)	($22.1)	($22.8)	($26.4)	($27.3)	($25.7)	($23.4)	($21.1)	($18.7)	($16.2)	($13.7)	($11.2)

CALCULATION OF MARGIN GEN COST IN CERTIFIED FISCAL PLAN

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ST SFO TOTAL COST	260,933	282,550	237,284	172,938	89,960					
ST SFO FIXED COST	30,278	30,811	26,317	21,553	10,966					
NET ST SFO COST	230,656	251,739	210,967	151,385	78,994					
ST SFO GENERATION MWH	3,311,734	2,717,107	1,949,662	1,285,433	634,566					
NET ST SFO COST/MWH	69.6	92.6	108.2	117.8	124.5					
ST GASTOTAL COST						78,877				
ST GAS FIXED COST						10,966				
NET ST GAS COST						67,911				
ST GAS GENERATION MWH						712,003				
NET ST GAS COST/MWH						95.4				
NG CC TOTAL COST							71,923	93,073	89,907	85,595
NG CC FIXED COST							31,081	31,573	32,171	32,780
NET NG CC COST							40,841	61,500	57,737	52,815
NG CC GENERATION MWH							544,408	810,413	746,313	670,327
NET NG CC COST/MWH							75	76	77	79

	2032	2033	2034	2035	2036	2037	2038	2039
NG CC TOTAL COST	80,914	109,240	112,556	111,451	57,269			
NG CC FIXED COST	33,486	34,031	34,680	35,333	17,979			
NET NG CC COST	47,427	75,208	77,876	76,117	39,290			
NG CC GENERATION MWH	591,539	921,825	940,981	909,681	461,293			
NET NG CC COST/MWH	80	82	83	84	85			
LARGE NG CC TOTAL COST						438,592	434,773	430,250
LARGE NG CC FIXED COST						148,698	149,053	149,418
NET LARGE NG CC COST						289,895	285,720	280,833
LARGE NG CC GENERATION MWH						3,452,707	3,360,965	3,261,489
NET LARGE NG CC COST/MWH						84.0	85.0	86.1

PPOA 99-100/Mwh valuation COMPARISON ESM IRP AND CERTIFIED FISCAL PLAN

PPOA Start Date Per FOMB		**2020**
PPOA Price $Mwh		**100**
PPOA Escalator		**2%**
PPOA Cap $/Mwh	**$**	**141**
Inflation		**2%**
Discount rate 2023-2045		**8.5%**
Discount Rate 2019-2022		**13.5%**
Hedge Premium 2025-2045		**6%**

	2020	2021	2022	2023	2024
CME Forward Hedge Premium v 2019 Forecast 10/14/19	6%	8%	10%	11%	12%

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MARGINAL UNIT		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ESM IRP BASE CASE		ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC
CFP 2020 SUBMITTED					ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-GAS	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC
MARGINAL FUEL AND VARIABLE O&M ($/Mwh)																												
MARGINAL GEN COST ESM IRP		118	124	121	122	124	125	67	69	70	72	71	72	73	75	76	78	80	81	82	83	84	85	86	86	87	88	89
MARGINAL GEN COST CFP					70	93	108	118	124	95	75	76	77	79	80	82	83	84	85	84.0	85.0	86.1	88	90	91	93	95	97
DIFFERENTIAL					-53	-32	-17	50	55	25	3	4	5	6	5	6	5	4	4	2	2	2	3	4	5	6	7	8
MARGIN GEN COST CFP + NEAR TERM		118	124	121	70	93	108	118	124	95	75	76	77	79	80	82	83	84	85	84	85	86	88	90	91	93	95	97
Certfied Fiscal plan is unhedged variable costs are slight more expensive than ESM IRP.																												
NPV UNHEDGED VARIABLE COST ONLY																												
NPV ESM IRP UNHEDGED VARIABLE COST ONLY	$794		124	121	122	$840.0																						
NPV CFP UNHEDGED VARIABLE COST ONLY	$805		124	121	70	$919.5																						
FULL AVOIDED COSTS																												
Add Environmental REC Credit		15.0	15.3	15.6	15.9	16.2	16.6	16.9	17.2	17.6	17.9	18.3	18.7	19.0	19.4	19.8	20.2	20.6	21.0	21.4	21.9	22.3	22.7	23.2	23.7	24.1	24.6	25.1
ADD: HEDGE VALUE FOR ESM IRP		0.0	8.0	9.7	12.0	13.3	15.5	5.4	5.6	5.6	5.7	5.7	5.8	5.8	6.0	6.1	6.2	6.4	6.5	6.6	6.6	6.7	6.8	6.8	6.9	7.0	7.1	7.1
AVOIDED COST ESM IRP		**133.0**	**147.4**	**146.7**	**150.4**	**153.9**	**157.2**	**89.6**	**92.2**	**93.4**	**95.2**	**95.4**	**96.8**	**97.6**	**100.1**	**101.7**	**104.1**	**106.5**	**108.2**	**110.3**	**111.6**	**112.9**	**114.3**	**115.7**	**117.0**	**118.5**	**119.9**	**121.3**
Combined Avoided Cost $/Mwh		133.0	147.4	146.7	150.4	153.9	157.2	89.6	92.2	93.4	95.2	95.4	96.8	97.6	100.1	101.7	104.1	106.5	108.2	110.3	111.6	112.9	114.3	115.7	117.0	118.5	119.9	121.3
$100/Mwh PPOA $/Mwh			100	102.0	104.0	106.1	108.2	110.4	112.6	114.9	117.2	119.5	121.9	124.3	126.8	129.4	131.9	134.6	137.3	140.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0
Net Savings/Cost v Avoid Cost $/Mwh			$47.4	$44.7	$46.3	$47.8	$49.0	($20.8)	($20.4)	($21.4)	($22.0)	($24.1)	($25.1)	($26.7)	($26.7)	($27.7)	($27.8)	($28.1)	($29.0)	($29.8)	($29.4)	($28.1)	($26.7)	($25.3)	($24.0)	($22.5)	($21.1)	($19.7)
2023-2045 NPV @ 8.5%						($115.71)																						
NPV 13.5% of 2020-2022+ NPV 13.5%of NPV2023-2045	$29.05		$47.4	$44.7	($69.38)																							
Add Environmental REC Credit		15.0	15.3	15.6	15.9	16.2	16.6	16.9	17.2	17.6	17.9	18.3	18.7	19.0	19.4	19.8	20.2	20.6	21.0	21.4	21.9	22.3	22.7	23.2	23.7	24.1	24.6	25.1
ADD: HEDGE VALUE FOR CFP IRP			8.0	9.7	6.8	9.9	13.4	9.4	10.0	7.6	6.0	6.1	6.2	6.3	6.4	6.5	6.6	6.7	6.8	6.7	6.8	6.9	7.0	7.2	7.3	7.5	7.6	7.8
AVOIDED COST CFP		**133.0**	**147.4**	**146.7**	**92.4**	**118.8**	**138.2**	**144.1**	**151.7**	**120.6**	**98.9**	**100.2**	**102.2**	**104.1**	**106.0**	**107.9**	**109.6**	**111.0**	**113.0**	**112.1**	**113.7**	**115.3**	**117.6**	**119.9**	**122.3**	**124.8**	**127.3**	**129.8**
$/100 Mwh PPOA $/Mwh			100	102.0	104.0	106.1	108.2	110.4	112.6	114.9	117.2	119.5	121.9	124.3	126.8	129.4	131.9	134.6	137.3	140.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0
Net Savings/Cost v Avoid Cost $/Mwh			$47.4	$44.7	($11.6)	$12.7	$30.0	$33.7	$39.1	$5.7	($18.2)	($19.3)	($19.7)	($20.2)	($20.8)	($21.5)	($22.4)	($23.6)	($24.3)	($27.9)	($27.3)	($25.7)	($23.4)	($21.1)	($18.7)	($16.2)	($13.7)	($11.2)
2023-2045 NPV @ 8.5%						($31.27)																						
NPV 13.5% of 2020-2022+ NPV 13.5%of NPV2023-2045	$47.15		$47.4	$44.7	($42.91)																							
CFP shows more value under same methodology																												
CFP starts in 2022 so 2020,2021 ESM data used to allow same discount comparison																												
In General, CFP hedge costs are more expensive NPV than ESM IRP																												
NPV AVOIDED COST ESM IRP	$1,012		147.4	146.7	150.4	$1,104.48																						
NPV AVOIDED COST CFP	$1,023		147.4	146.7	92.4	$1,188.92																						
DIFFERENCE IN NPV $/MWH	$11																											
DIFFERENCE IN NPV $/MWH					$26.47																							

CALCULATION OF MARGIN GEN COST IN CERTIFIED FISCAL PLAN

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
ST SFO TOTAL COST	260,933	282,550	237,284	172,938	89,960													
ST SFO FIXED COST	30,278	30,811	26,317	21,553	10,966													
NET ST SFO COST	230,656	251,739	210,967	151,385	78,994													
ST SFO GENERATION MWH	3,311,734	2,717,107	1,949,662	1,285,433	634,566													
NET ST SFO COST/MWH	69.6	92.6	108.2	117.8	124.5													
ST GASTOTAL COST						78,877												
ST GAS FIXED COST						10,966												
NET ST GAS COST						67,911												
ST GAS GENERATION MWH						712,003												
NET ST GAS COST/MWH						95.4												
NG CC TOTAL COST							71,923	93,073	89,907	85,595	80,914	109,240	112,556	111,455	57,269			
NG CC FIXED COST							31,081	31,573	32,171	32,780	33,486	34,031	34,680	35,333	17,979			
NET NG CC COST							40,841	61,500	57,737	52,815	47,427	75,208	77,876	76,117	39,290			
NG CC GENERATION MWH							544,408	810,413	746,312	670,327	591,539	921,825	940,981	909,681	461,293			
NET NG CC COST/MWH							75	76	77	79	80	82	83	84	85			
LARGE NG CC TOTAL COST																438,592	434,773	430,250
LARGE NG CC FIXED COST																148,698	149,053	149,418
NET LARGE NG CC COST																289,895	285,720	280,833
LARGE NG CC GENERATION MWH																3,452,707	3,360,965	3,261,489
NET LARGE NG CC COST/MWH																84.0	85.0	86.1

CIRO calculation COMPARISON ESM IRP AND CERTIFIED FISCAL PLAN

PPOA start for Comparison to NEP 2019 rpt		**2019**					
PPOA Price $Mwh		**98.9**					
PPOA Escalator		**2%**					
PPOA Cap $/Mwh	$	**141**					
Inflation		2%					
Discount rate 2023-2045		8.5%					
Discount Rate 2019-2022		13.5%					
Hedge Premium 2025-2045		6%					
			2020	2021	2022	2023	2024
CME Forward Hedge Premium v 2019 Forecast 10/14/19			6%	8%	10%	11%	12%

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MARGINAL UNIT		2019	2020	2021	2022	2023	2024	2025	2026	2027
ESM IRP BASE CASE		ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	GAS CC	GAS CC	GAS CC
CFP 2020 SUBMITTED					ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-GAS
MARGINAL FUEL AND VARIABLE O&M ($/Mwh)										
MARGINAL GEN COST ESM IRP		118	124	121	122	124	125	67	69	70
MARGINAL GEN COST CFP					70	93	108	118	124	95
DIFFERENTIAL					-53	-32	-17	50	55	25
MARGIN GEN COST CFP + NEAR TERM		118	124	121	70	93	108	118	124	95
Certfied Fiscal plan is unhedged variable costs are slight more expensive than ESM IRP.										
NPV UNHEDGED VARIABLE COST ONLY										
NPV ESM IRP UNHEDGED VARIABLE COST ONLY	$794		124	121	122	$840.0				
NPV CFP UNHEDGED VARIABLE COST ONLY	$805		124	121	70	$919.5				
FULL AVOIDED COSTS										
Add Environmental REC Credit		15.0	15.3	15.6	15.9	16.2	16.6	16.9	17.2	17.6
ADD: HEDGE VALUE FOR ESM IRP		0.0	8.0	9.7	12.0	13.3	15.5	5.4	5.6	5.6
AVOIDED COST ESM IRP		**133.0**	**147.4**	**146.7**	**150.4**	**153.9**	**157.2**	**89.6**	**92.2**	**93.4**
Combined Avoided Cost $/Mwh		133.0	147.4	146.7	150.4	153.9	157.2	89.6	92.2	93.4
Ciro PPOA $/Mwh		98.9	100.878	102.9	105.0	107.1	109.2	111.4	113.6	115.9
Net Savings/Cost v Avoid Cost $/Mwh			$46.6	$43.8	$45.4	$46.9	$48.0	($21.8)	($21.4)	($22.4)
2023-2045 NPV @ 8.5%						($124.29)				
NPV 13.5% of 2020-2022+ NPV 13.5%of NPV2023-2045	$21.08		$46.6	$43.8	($78.88)					
Note minor difference vs original NEP sheet										
Add Environmental REC Credit		15.0	15.3	15.6	15.9	16.2	16.6	16.9	17.2	17.6
ADD: HEDGE VALUE FOR CFP IRP			8.0	9.7	6.8	9.9	13.4	9.4	10.0	7.6
AVOIDED COST CFP		**133.0**	**147.4**	**146.7**	**92.4**	**118.8**	**138.2**	**144.1**	**151.7**	**120.6**
CIRO PPOA $/Mwh		98.9	100.878	102.896	104.95347	107.05254	109.19359	111.3774633	113.6050125	115.8771128
Net Savings/Cost v Avoid Cost $/Mwh			$46.6	$43.8	($12.6)	$11.8	$29.0	$32.7	$38.1	$4.7
2023-2045 NPV @ 8.5%						($39.86)				
NPV 13.5% of 2020-2022+ NPV 13.5%of NPV2023-2045	$39.19		$46.6	$43.8	($52.41)					
CFP shows more value under same methodology										
CFP starts in 2022 so 2020,2021 ESM data used to allow same discount comparison										
In General, CFP hedge costs are more expensive NPV than ESM IRP										
NPV AVOIDED COST ESM IRP	$1,012		147.4	146.7	150.4	$1,104.48				
NPV AVOIDED COST CFP	$1,023		147.4	146.7	92.4	$1,188.92				
DIFFERENCE IN NPV $/MWH	$11									
DIFFERENCE IN NPV $/MWH					$26.47					

MARGINAL UNIT	2028	2029	2030	2031	2032	2033	2034	2035	2036
ESM IRP BASE CASE	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC
CFP 2020 SUBMITTED	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC
MARGINAL GEN COST ESM IRP	72	71	72	73	75	76	78	80	81
MARGINAL GEN COST CFP	75	76	77	79	80	82	83	84	85
DIFFERENTIAL	3	4	5	6	5	6	5	4	4
MARGIN GEN COST CFP + NEAR TERM	75	76	77	79	80	82	83	84	85
Add Environmental REC Credit	17.9	18.3	18.7	19.0	19.4	19.8	20.2	20.6	21.0
ADD: HEDGE VALUE FOR ESM IRP	5.7	5.7	5.8	5.8	6.0	6.1	6.2	6.4	6.5
AVOIDED COST ESM IRP	**95.2**	**95.4**	**96.8**	**97.6**	**100.1**	**101.7**	**104.1**	**106.5**	**108.2**
Combined Avoided Cost $/Mwh	95.2	95.4	96.8	97.6	100.1	101.7	104.1	106.5	108.2
Ciro PPOA $/Mwh	118.2	120.6	123.0	125.4	127.9	130.5	133.1	135.8	138.5
Net Savings/Cost v Avoid Cost $/Mwh	($23.0)	($25.2)	($26.1)	($27.8)	($27.8)	($28.8)	($29.0)	($29.3)	($30.2)
Add Environmental REC Credit	17.9	18.3	18.7	19.0	19.4	19.8	20.2	20.6	21.0
ADD: HEDGE VALUE FOR CFP IRP	6.0	6.1	6.2	6.3	6.4	6.5	6.6	6.7	6.8
AVOIDED COST CFP	**98.9**	**100.2**	**102.2**	**104.1**	**106.0**	**107.9**	**109.6**	**111.0**	**113.0**
CIRO PPOA $/Mwh	118.194655	120.5585481	122.9697191	125.4291135	127.9376958	130.4964497	133.1063787	135.7685062	138.4838764
Net Savings/Cost v Avoid Cost $/Mwh	($19.2)	($20.3)	($20.8)	($21.3)	($21.9)	($22.6)	($23.5)	($24.8)	($25.5)

MARGINAL UNIT	2037	2038	2039	2040	2041	2042	2043	2044	2045
ESM IRP BASE CASE	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC
CFP 2020 SUBMITTED	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC
MARGINAL GEN COST ESM IRP	82	83	84	85	86	86	87	88	89
MARGINAL GEN COST CFP	84.0	85.0	86.1	88	90	91	93	95	97
DIFFERENTIAL	2	2	2	3	4	5	6	7	8
MARGIN GEN COST CFP + NEAR TERM	84	85	86	88	90	91	93	95	97
Add Environmental REC Credit	21.4	21.9	22.3	22.7	23.2	23.7	24.1	24.6	25.1
ADD: HEDGE VALUE FOR ESM IRP	6.6	6.6	6.7	6.8	6.8	6.9	7.0	7.1	7.1
AVOIDED COST ESM IRP	**110.3**	**111.6**	**112.9**	**114.3**	**115.7**	**117.0**	**118.5**	**119.9**	**121.3**
Combined Avoided Cost $/Mwh	110.3	111.6	112.9	114.3	115.7	117.0	118.5	119.9	121.3
Ciro PPOA $/Mwh	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0
Net Savings/Cost v Avoid Cost $/Mwh	($30.7)	($29.4)	($28.1)	($26.7)	($25.3)	($24.0)	($22.5)	($21.1)	($19.7)
Add Environmental REC Credit	21.4	21.9	22.3	22.7	23.2	23.7	24.1	24.6	25.1
ADD: HEDGE VALUE FOR CFP IRP	6.7	6.8	6.9	7.0	7.2	7.3	7.5	7.6	7.8
AVOIDED COST CFP	**112.1**	**113.7**	**115.3**	**117.6**	**119.9**	**122.3**	**124.8**	**127.3**	**129.8**
CIRO PPOA $/Mwh	141	141	141	141	141	141	141	141	141
Net Savings/Cost v Avoid Cost $/Mwh	($28.9)	($27.3)	($25.7)	($23.4)	($21.1)	($18.7)	($16.2)	($13.7)	($11.2)

CALCULATION OF MARGIN GEN COST IN CERTIFIED FISCAL PLAN

ST SFO TOTAL COST	260,933	282,550	237,284	172,938	89,960	
ST SFO FIXED COST	30,278	30,811	26,317	21,553	10,966	
NET ST SFO COST	230,656	251,739	210,967	151,385	78,994	
ST SFO GENERATION MWH	3,311,734	2,717,107	1,949,662	1,285,433	634,566	
NET ST SFO COST/MWH	69.6	92.6	108.2	117.8	124.5	
ST GASTOTAL COST						78,877
ST GAS FIXED COST						10,966
NET ST GAS COST						67,911
ST GAS GENERATION MWH						712,003
NET ST GAS COST/MWH						95.4

NG CC TOTAL COST	71,923	93,073	89,907	85,595	80,914	109,240	112,556	111,451	57,269
NG CC FIXED COST	31,081	31,573	32,171	32,780	33,486	34,031	34,680	35,333	17,979
NET NG CC COST	40,841	61,500	57,737	52,815	47,427	75,208	77,876	76,117	39,290
NG CC GENERATION MWH	544,408	810,413	746,313	670,327	591,539	921,825	940,981	909,681	461,293
NET NG CC COST/MWH	75	76	77	79	80	82	83	84	85

LARGE NG CC TOTAL COST	438,592	434,773	430,250
LARGE NG CC FIXED COST	148,698	149,053	149,418
NET LARGE NG CC COST	289,895	285,720	280,833
LARGE NG CC GENERATION MWH	3,452,707	3,360,965	3,261,489
NET LARGE NG CC COST/MWH	84.0	85.0	86.1

PPOA at ~99-100/Mwh valuation COMPARISON ESM IRP AND CERTIFIED FISCAL PLAN

PPOA start for Comparison to NEP 2019 rpt		**2019**
PPOA Price $Mwh		**100**
PPOA Escalator		**2%**
PPOA Cap $/Mwh	**$**	**141**
Inflation		2%
Discount rate 2023-2045		8.5%
Discount Rate 2019-2022		13.5%
Hedge Premium 2025-2045		8%

	2020	2021	2022	2023	2024
CME Forward Hedge Premium v 2019 Forecast 10/14/19	6%	8%	10%	11%	12%

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MARGINAL UNIT		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ESM IRP BASE CASE		ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC
CFP 2020 SUBMITTED					ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-GAS	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC
MARGINAL FUEL AND VARIABLE O&M ($/Mwh)																												
MARGINAL GEN COST ESM IRP		118	124	121	122	124	125	67	69	70	72	71	72	73	75	76	78	80	81	82	83	84	85	86	86	87	88	89
MARGINAL GEN COST CFP					70	93	108	118	124	95	75	76	77	79	80	82	83	84	85	84.0	85.0	86.1	88	90	91	93	95	97
DIFFERENTIAL					-53	-32	-17	50	55	25	3	4	5	6	5	6	5	4	4	2	2	2	3	4	5	6	7	8
MARGIN GEN COST CFP + NEAR TERM		118	124	121	70	93	108	118	124	95	75	76	77	79	80	82	83	84	85	84	85	86	88	90	91	93	95	97
Certified Fiscal plan is unhedged variable costs are slight more expensive than ESM IRP.																												
NPV UNHEDGED VARIABLE COST ONLY																												
NPV ESM IRP UNHEDGED VARIABLE COST ONLY	$794		124	121	122	$840.0																						
NPV CFP UNHEDGED VARIABLE COST ONLY	$805		124	121	70	$919.5																						
FULL AVOIDED COSTS																												
Add Environmental REC Credit		15.0	15.3	15.6	15.9	16.2	16.6	16.9	17.2	17.6	17.9	18.3	18.7	19.0	19.4	19.8	20.2	20.6	21.0	21.4	21.9	22.3	22.7	23.2	23.7	24.1	24.6	25.1
ADD: HEDGE VALUE FOR ESM IRP		0.0	8.0	9.7	12.0	13.3	15.5	5.4	5.6	5.6	5.7	5.7	5.8	5.8	6.0	6.1	6.2	6.4	6.5	6.6	6.6	6.7	6.8	6.8	6.9	7.0	7.1	7.1
AVOIDED COST ESM IRP		**133.0**	**147.4**	**146.7**	**150.4**	**153.9**	**157.2**	**89.6**	**92.2**	**93.4**	**95.2**	**95.4**	**96.8**	**97.6**	**100.1**	**101.7**	**104.1**	**106.5**	**108.2**	**110.3**	**111.6**	**112.9**	**114.3**	**115.7**	**117.0**	**118.5**	**119.9**	**121.3**
Combined Avoided Cost $/Mwh		133.0	147.4	146.7	150.4	153.9	157.2	89.6	92.2	93.4	95.2	95.4	96.8	97.6	100.1	101.7	104.1	106.5	108.2	110.3	111.6	112.9	114.3	115.7	117.0	118.5	119.9	121.3
$100/Mwh PPOA $/Mwh		100	102	104.0	106.1	108.2	110.4	112.6	114.9	117.2	119.5	121.9	124.3	126.8	129.4	131.9	134.6	137.3	140.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0
Net Savings/Cost v Avoid Cost $/Mwh			$45.4	$42.7	$44.2	$45.7	$46.8	($23.1)	($22.7)	($23.7)	($24.3)	($26.5)	($27.5)	($29.2)	($29.2)	($30.3)	($30.4)	($30.8)	($31.8)	($30.7)	($29.4)	($28.1)	($26.7)	($25.3)	($24.0)	($22.5)	($21.1)	($19.7)
2023-2045 NPV @ 8.5%						($134.90)																						
NPV 13.5% of 2020-2022+ NPV 13.5%of NPV2023-2045	$11.15		$45.4	$42.7	($90.65)																							
Note minor difference vs original NEP sheet																												
Add Environmental REC Credit		15.0	15.3	15.6	15.9	16.2	16.6	16.9	17.2	17.6	17.9	18.3	18.7	19.0	19.4	19.8	20.2	20.6	21.0	21.4	21.9	22.3	22.7	23.2	23.7	24.1	24.6	25.1
ADD: HEDGE VALUE FOR CFP IRP			8.0	9.7	6.8	9.9	13.4	9.4	10.0	7.6	6.0	6.1	6.2	6.3	6.4	6.5	6.6	6.7	6.8	6.7	6.8	6.9	7.0	7.2	7.3	7.5	7.6	7.8
AVOIDED COST CFP		**133.0**	**147.4**	**146.7**	**92.4**	**118.8**	**138.2**	**144.1**	**151.7**	**120.6**	**98.9**	**100.2**	**102.2**	**104.1**	**106.0**	**107.9**	**109.6**	**111.0**	**113.0**	**112.1**	**113.7**	**115.3**	**117.6**	**119.9**	**122.3**	**124.8**	**127.3**	**129.8**
$/100 Mwh PPOA $/Mwh		100	102	104.0	106.1	108.2	110.4	112.6	114.9	117.2	119.5	121.9	124.3	126.8	129.4	131.9	134.6	137.3	140.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0
Net Savings/Cost v Avoid Cost $/Mwh			$45.4	$42.7	($13.7)	$10.6	$27.8	$31.5	$36.8	$3.4	($20.6)	($21.7)	($22.1)	($22.7)	($23.4)	($24.0)	($25.0)	($26.3)	($27.0)	($28.9)	($27.3)	($25.7)	($23.4)	($21.1)	($18.7)	($16.2)	($13.7)	($11.2)
2023-2045 NPV @ 8.5%						($50.46)																						
NPV 13.5% of 2020-2022+ NPV 13.5%of NPV2023-2045	$29.26		$45.4	$42.7	($64.18)																							
CFP shows more value under same methodology																												
CFP starts in 2022 so 2020,2021 ESM data used to allow same discount comparison																												
In General, CFP hedge costs are more expensive NPV than ESM IRP																												
NPV AVOIDED COST ESM IRP	$1,012		147.4	146.7	150.4	$1,104.48																						
NPV AVOIDED COST CFP	$1,023		147.4	146.7	92.4	$1,188.92																						
DIFFERENCE IN NPV $/MWH	$11																											
DIFFERENCE IN NPV $/MWH					$26.47																							

CALCULATION OF MARGIN GEN COST IN CERTIFIED FISCAL PLAN

ST SFO TOTAL COST	260,933	282,550	237,284	172,938	89,960													
ST SFO FIXED COST	30,278	30,811	26,317	21,553	10,966													
NET ST SFO COST	230,656	251,739	210,967	151,385	78,994													
ST SFO GENERATION MWH	3,311,734	2,717,107	1,949,662	1,285,433	634,566													
NET ST SFO COST/MWH	69.6	92.6	108.2	117.8	124.5													
ST GASTOTAL COST						78,877												
ST GAS FIXED COST						10,966												
NET ST GAS COST						67,911												
ST GAS GENERATION MWH						712,003												
NET ST GAS COST/MWH						95.4												
NG CC TOTAL COST							71,923	93,073	89,907	85,595	80,914	109,240	112,556	111,451	57,269			
NG CC FIXED COST							31,081	31,573	32,171	32,780	33,486	34,031	34,680	35,333	17,979			
NET NG CC COST							40,841	61,500	57,737	52,815	47,427	75,208	77,876	76,117	39,290			
NG CC GENERATION MWH							544,408	810,413	746,313	670,327	591,539	921,825	940,981	909,681	461,293			
NET NG CC COST/MWH							75	76	77	79	80	82	83	84	85			
LARGE NG CC TOTAL COST																438,592	434,773	430,250
LARGE NG CC FIXED COST																148,698	149,053	149,418
NET LARGE NG CC COST																289,895	285,720	280,833
LARGE NG CC GENERATION MWH																3,452,707	3,360,965	3,261,489
NET LARGE NG CC COST/MWH																84.0	85.0	86.1

Xzerta valuation COMPARISON ESM IRP AND CERTIFIED FISCAL PLAN

PPOA start for Comparison to NEP 2019 rpt		**2019**
PPOA Price $Mwh		**99**
PPOA Escalator		**1%**
PPOA Cap $/Mwh	$	**126**
Inflation		2%
Discount rate 2023-2045		8.5%
Discount Rate 2019-2022		13.5%
Hedge Premium 2025-2045		8%

	2020	2021	2022	2023	2024
CME Forward Hedge Premium v 2019 Forecast 10/14/19	6%	8%	10%	11%	12%

MARGINAL UNIT		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
ESM IRP BASE CASE		ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC
CFP 2020 SUBMITTED					ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-HFO	ST-GAS	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC	LARGE GAS CC
MARGINAL FUEL AND VARIABLE O&M ($/Mwh)																												
MARGINAL GEN COST ESM IRP		118	124	121	122	124	125	67	69	70	72	71	72	73	75	76	78	80	81	82	83	84	85	86	86	87	88	89
MARGINAL GEN COST CFP					70	93	108	118	124	95	75	76	77	79	80	82	83	84	85	84.0	85.0	86.1	88	90	91	93	95	97
DIFFERENTIAL					-53	-32	-17	50	55	25	3	4	5	6	5	6	5	4	4	2	2	2	3	4	5	6	7	8
MARGIN GEN COST CFP + NEAR TERM		118	124	121	70	93	108	118	124	95	75	76	77	79	80	82	83	84	85	84	85	86	88	90	91	93	95	97
Certfied Fiscal plan is unhedged variable costs are slight more expensive than ESM IRP.																												
NPV UNHEDGED VARIABLE COST ONLY																												
NPV ESM IRP UNHEDGED VARIABLE COST ONLY	$794		124	121	122	$840.0																						
NPV CFP UNHEDGED VARIABLE COST ONLY	$805		124	121	70	$919.5																						
FULL AVOIDED COSTS																												
Add Environmental REC Credit		15.0	15.3	15.6	15.9	16.2	16.6	16.9	17.2	17.6	17.9	18.3	18.7	19.0	19.4	19.8	20.2	20.6	21.0	21.4	21.9	22.3	22.7	23.2	23.7	24.1	24.6	25.1
ADD: HEDGE VALUE FOR ESM IRP		0.0	8.0	9.7	12.0	13.3	15.5	5.4	5.6	5.6	5.7	5.7	5.8	5.8	6.0	6.1	6.2	6.4	6.5	6.6	6.6	6.7	6.8	6.8	6.9	7.0	7.1	7.1
AVOIDED COST ESM IRP		**133.0**	**147.4**	**146.7**	**150.4**	**153.9**	**157.2**	**89.6**	**92.2**	**93.4**	**95.2**	**95.4**	**96.8**	**97.6**	**100.1**	**101.7**	**104.1**	**106.5**	**108.2**	**110.3**	**111.6**	**112.9**	**114.3**	**115.7**	**117.0**	**118.5**	**119.9**	**121.3**
Combined Avoided Cost $/Mwh		133.0	147.4	146.7	150.4	153.9	157.2	89.6	92.2	93.4	95.2	95.4	96.8	97.6	100.1	101.7	104.1	106.5	108.2	110.3	111.6	112.9	114.3	115.7	117.0	118.5	119.9	121.3
Xzerta PPOA $/Mwh		99	99.99	101.0	102.0	103.0	104.0	105.1	106.1	107.2	108.3	109.4	110.5	111.6	112.7	113.8	114.9	116.1	117.2	118.4	119.6	120.8	121.6	121.6	121.6	121.6	121.6	121.6
Net Savings/Cost v Avoid Cost $/Mwh			$47.4	$45.7	$48.4	$50.9	$53.2	($15.5)	($14.0)	($13.8)	($13.1)	($14.0)	($13.6)	($13.9)	($12.5)	($12.1)	($10.8)	($9.6)	($9.0)	($8.2)	($8.0)	($7.9)	($7.3)	($5.9)	($4.6)	($3.1)	($1.7)	($0.3)
2023-2045 NPV @ 8.5%						($1.00)																						
NPV 13.5% of 2020-2022+ NPV 13.5%of NPV2023-2045	$109.68		$47.4	$45.7	$47.36																							
Note: higher value vs NEP Dec report due to inflation term spreadsheet error on avoided cost nor corrected																												
Add Environmental REC Credit		15.0	15.3	15.6	15.9	16.2	16.6	16.9	17.2	17.6	17.9	18.3	18.7	19.0	19.4	19.8	20.2	20.6	21.0	21.4	21.9	22.3	22.7	23.2	23.7	24.1	24.6	25.1
ADD: HEDGE VALUE FOR CFP IRP			8.0	9.7	6.8	9.9	13.4	9.4	10.0	7.6	6.0	6.1	6.3	6.3	6.4	6.5	6.6	6.7	6.8	6.7	6.8	6.9	7.0	7.2	7.3	7.5	7.6	7.8
AVOIDED COST CFP		**133.0**	**147.4**	**146.7**	**92.4**	**118.8**	**138.2**	**144.1**	**151.7**	**120.6**	**98.9**	**100.2**	**102.2**	**104.1**	**106.0**	**107.9**	**109.6**	**111.0**	**113.0**	**112.1**	**113.7**	**115.3**	**117.6**	**119.9**	**122.3**	**124.8**	**127.3**	**129.8**
Xzerta PPOA $/Mwh		99	99.99	101.0	102.0	103.0	104.0	105.1	106.1	107.2	108.3	109.4	110.5	111.6	112.7	113.8	114.9	116.1	117.2	118.4	119.6	120.8	121.6	121.6	121.6	121.6	121.6	121.6
Net Savings/Cost v Avoid Cost $/Mwh			$47.4	$45.7	($9.6)	$15.8	$34.1	$39.0	$45.5	$13.4	($9.3)	($9.1)	($8.2)	($7.4)	($6.7)	($5.9)	($5.4)	($5.1)	($4.3)	($6.3)	($5.9)	($5.5)	($4.0)	($1.7)	$0.7	$3.2	$5.7	$8.2
2023-2045 NPV @ 8.5%						$83.43																						
NPV 13.5% of 2020-2022+ NPV 13.5%of NPV2023-2045	$127.79		$47.4	$45.7	$73.83																							
CFP shows more value under same methodology																												
CFP starts in 2022 so 2020,2021 ESM data used to allow same discount comparison																												
In General, CFP hedge costs are more expensive NPV than ESM IRP																												
NPV AVOIDED COST ESM IRP	$1,012		147.4	146.7	150.4	$1,104.48																						
NPV AVOIDED COST CFP	$1,023		147.4	146.7	92.4	$1,188.92																						
DIFFERENCE IN NPV $/MWH	$11																											
DIFFERENCE IN NPV $/MWH					$26.47																							

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CALCULATION OF MARGIN GEN COST IN CERTIFIED FISCAL PLAN

ST SFO TOTAL COST	260,933	282,550	237,284	172,938	89,960													
ST SFO FIXED COST	30,278	30,811	26,317	21,553	10,966													
NET ST SFO COST	230,656	251,739	210,967	151,385	78,994													
ST SFO GENERATION MWH	3,311,734	2,717,107	1,949,662	1,285,433	634,566													
NET ST SFO COST/MWH	69.6	92.6	108.2	117.8	124.5													
ST GASTOTAL COST						78,877												
ST GAS FIXED COST						10,966												
NET ST GAS COST						67,911												
ST GAS GENERATION MWH						712,003												
NET ST GAS COST/MWH						95.4												
NG CC TOTAL COST							71,923	93,073	89,907	85,595	80,914	109,240	112,556	111,451	57,269			
NG CC FIXED COST							31,081	31,573	32,171	32,780	33,486	34,031	34,680	35,333	17,979			
NET NG CC COST							40,841	61,500	57,737	52,815	47,427	75,208	77,876	76,117	39,290			
NG CC GENERATION MWH							544,408	810,413	746,313	670,327	591,539	921,825	940,981	909,681	461,293			
NET NG CC COST/MWH							75	76	77	79	80	82	83	84	85			
LARGE NG CC TOTAL COST																438,592	434,773	430,250
LARGE NG CC FIXED COST																148,698	149,053	149,418
NET LARGE NG CC COST																289,895	285,720	280,833
LARGE NG CC GENERATION MWH																3,452,707	3,360,965	3,261,489
NET LARGE NG CC COST/MWH																84.0	85.0	86.1

PREPA LEGACY PPOA RANKING SCORECARD

VERSION Rev 3_Jan FOMB

DATE 27-Jan

FOMB Request to compare vs CFP, Projects all start in 2020, discounted to 2020

Updated 2019 Start

Analysis Algorithm

a) Lifetime mwh calculated by project based on submitted capacity factor and degradation rate x MW capacity summed over lifetime. Projects without this data were assigned standard Siemens Capa

b). NPV of output is lifetime MWH x NPV/Mwh depending on price offered as defined by table below. See NEP 2019 Report for derivation

c). Cost of interconnect derived from S&L Report CS-0034, Final Rev 1, June 19 2020

d). Public Benefit = (b)-'c'

e). Public Value/MW = (d)/MW capacity

			FOMB Request			
		ESM	ESM	CFP		
		Start 2019	Start 2020	Start 2020		
Value to Ratepayer Based on Price/Cap/Escalation	PPA	$/Mwh	$/Mwh	$/Mwh		
NPV Value/Mwh @ Blended discount rate: Lower Cost	10¢/12.6¢,1%	109.7	118.7	136.8	Xzerta	ESM 2019 fixes inflation error on earlier reportec
Basecase NPV Value/Mwh @ Blended discount rate	9.75¢/14.1¢,2%	37.7	51	69		
Basecase NPV Value/Mwh @ Blended discount rate	9.8¢/14.1¢,2%	32.6	47	65		
Basecase NPV Value/Mwh @ Blended discount rate	9.85/14.1¢,2%	27.9	42	60.9		
Basecase NPV Value/Mwh @ Blended discount rate	9.9/14.1¢,2%	20	39	57.2	CIRO 1 Value is $21/Mwh for 2019 ESM start	
Basecase NPV Value/Mwh @ Blended discount rate	10¢/14.1¢,2%	**11**	29	47	**See NEP Report, p 29 NPV Savings per MWh no MATS Compliance fi**	

	Public Benefit Test							
	SIZE	PPOA	Lifetime MWh (a)	NPV of output (b)	Cost of Interconnection 'c'	NPV Public Benefit (d)	Public benefit?	Public Value €
PROJECT	(MW)	$/Mwh	(Mwh)	$	$		Y/N	$/MW
Xzerta-Tec* price is 99, 1% escalator, cap at 12.6	60	99	2,583,574	306,670,234	3,210,000	303,460,234	Y	$ 5,057,671
Caracol	30	97.5	1,291,787	65,881,137	1,030,000	64,851,137	Y	$ 2,161,705
Sierra	25	97.5	1,076,489	54,900,939	3,405,000	51,495,939	Y	$ 2,059,838
Montalva Solar Farm	80	98.5	4,035,188	169,477,896	15,740,000	153,737,896	Y	$ 1,921,724
CIRO One	90	98.9	4,112,930	160,404,270	8,100,000	152,304,270	Y	$ 1,692,270
ReSun w/ Blue Beetle	35	99	1,507,085	57,269,230	2,640,000	54,629,230	Y	$ 1,560,835
Aetnas (Based on Developer letter 20 MW)	20	98	845,984	39,761,248	9,300,000	30,461,248	Y	$ 1,523,062
ReSun w/o Blue Beetle	35	99	1,507,085	57,269,230	4,420,000	52,849,230	Y	$ 1,509,978
Blue Beetle w Re Sun	30	99.9	1,359,900	39,437,100	2,940,000	36,497,100	Y	$ 1,216,570
Blue Beetle w/o Re Sun	30	99.9	1,359,900	39,437,100	4,720,000	34,717,100	Y	$ 1,157,237
REA Hatillo N (1)	25	99.99	1,076,489	31,218,181	4,000,000	27,218,181	Y	$ 1,088,727
Solaner	35	100	1,343,714	38,967,706	4,100,000	34,867,706	Y	$ 996,220
Guayama Solar Energy	25	99.5	1,076,489	31,218,181	4,910,000	26,308,181	Y	$ 1,052,327
Solar Blue	25	99.5	1,076,489	31,218,181	5,840,000	25,378,181	Y	$ 1,015,127
REA Vega Baja	25	100	1,164,183	33,761,307	8,100,000	25,661,307	Y	$ 1,026,452
Solar Project San Juan	20	100	863,287	25,035,323	7,800,000	17,235,323	Y	$ 861,766
Fonroche Vega Baja	15	100	647,350	18,773,150	4,510,000	14,263,150	Y	950,877
Standard Capacity Factor 22%								
Morovis not shown, DQ due to late response								
(1). Corrected speadsheet error on Mwh produced								

PREPA LEGACY PPOA RANKING SCORECARD

VERSION Rev 3_Jan FOMB

DATE 27-Jan

FOMB Request to compare vs CFP, Projects all start in 2020, discounted to 2020

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a) Lifetime mwh calculated by project based on submitted capacity factor and degradation rate x MW capacity summed over lifetime. Projects without this data were assigned standard Siemens Capa

b). NPV of output is lifetime MWH x NPV/Mwh depending on price offered as defined by table below. See NEP 2019 Report for derivation

c). Cost of interconnect derived from S&L Report CS-0034, Final Rev 1, June 19 2020

d). Public Benefit = (b)-'c'

e). Public Value/MW = (d)/MW capacity

			FOMB Request		
		ESM	ESM	CFP	
		Start 2019	Start 2020	Start 2020	
Value to Ratepayer Based on Price/Cap/Escalation	PPA	$/Mwh	$/Mwh	$/Mwh	
NPV Value/Mwh @ Blended discount rate: Lower Cost	10¢/12.6¢,1%	109.7	118.7	136.8	Xzerta ESM 2019 fixes inflation error on earlier reportec
Basecase NPV Value/Mwh @ Blended discount rate	9.75¢/14.1¢,2%	37.7	51	69	
Basecase NPV Value/Mwh @ Blended discount rate	9.8¢/14.1¢,2%	32.6	47	65	
Basecase NPV Value/Mwh @ Blended discount rate	9.85/14.1¢,2%	27.9	42	60.9	
Basecase NPV Value/Mwh @ Blended discount rate	9.9/14.1¢,2%	20	39	57.2	CIRO 1 Value is $21/Mwh for 2019 ESM start
Basecase NPV Value/Mwh @ Blended discount rate	10¢/14.1¢,2%	**11**	29	47	**See NEP Report, p 29 NPV Savings per MWh no MATS Compliance fi**

	Public Benefit Test							
	SIZE	PPOA	Lifetime MWh (a)	NPV of output (b)	Cost of Interconnection 'c'	NPV Public Benefit (d)	Public benefit?	Public Value €
PROJECT	(MW)	$/Mwh	(Mwh)	$	$		Y/N	$/MW
Xzerta-Tec* price is 99, 1% escalator, cap at 12.6	60	99	2,583,574	353,432,923	3,210,000	350,222,923	Y	$ 5,837,049
Caracol	30	97.5	1,291,787	89,133,303	1,030,000	88,103,303	Y	$ 2,936,777
Sierra	25	97.5	1,076,489	74,277,741	3,405,000	70,872,741	Y	$ 2,834,910
Montalva Solar Farm	80	98.5	4,035,188	245,742,949	15,740,000	230,002,949	Y	$ 2,875,037
CIRO One	90	98.9	4,112,930	235,259,596	8,100,000	227,159,596	Y	$ 2,523,996
ReSun w/ Blue Beetle	35	99	1,507,085	84,698,177	2,640,000	82,058,177	Y	$ 2,344,519
Aetnas (Based on Developer letter 20 MW)	20	98	845,984	54,988,960	9,300,000	45,688,960	Y	$ 2,284,448
ReSun w/o Blue Beetle	35	99	1,507,085	84,698,177	4,420,000	80,278,177	Y	$ 2,293,662
Blue Beetle w Re Sun	30	99.9	1,359,900	63,915,300	2,940,000	60,975,300	Y	$ 2,032,510
Blue Beetle w/o Re Sun	30	99.9	1,359,900	63,915,300	4,720,000	59,195,300	Y	$ 1,973,177
REA Hatillo N (1)	25	99.99	1,076,489	50,594,983	4,000,000	46,594,983	Y	$ 1,863,799
Solaner	35	100	1,343,714	63,154,558	4,100,000	59,054,558	Y	$ 1,687,273
Guayama Solar Energy	25	99.5	1,076,489	50,594,983	4,910,000	45,684,983	Y	$ 1,827,399
Solar Blue	25	99.5	1,076,489	50,594,983	5,840,000	44,754,983	Y	$ 1,790,199
REA Vega Baja	25	100	1,164,183	54,716,601	8,100,000	46,616,601	Y	$ 1,864,664
Solar Project San Juan	20	100	863,287	40,574,489	7,800,000	32,774,489	Y	$ 1,638,724
Fonroche Vega Baja	15	100	647,350	30,425,450	4,510,000	25,915,450	Y	1,727,697
Standard Capacity Factor 22%								
Morovis not shown, DQ due to late response								
(1). Corrected speadsheet error on Mwh produced								